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April 25, 2014

VIA ELECTRONIC FILING

Ms. Gail L. Mount
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

Re: Biennial Determination of Avoided Cost Rates for Electric Utility Purchases From Qualifying Facilities – 2014
Docket No. E-100, Sub 140

Dear Ms. Mount:

Enclosed please find for filing in connection with the above-referenced matter the Testimony and Exhibits of Kendal C. Bowman, Glen A. Snider and Lawrence Makovich on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.

Thank you for your assistance in this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,

Charles A. Castle

<u>CERTIFICATE OF SERVICE</u>

I certify that a copy of Testimony and Exhibits of Kendal C. Bowman, Glen A. Snider, and Lawrence Makovich on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, Inc. has been served by electronic mail, hand delivery, or by depositing a copy in the United States Mail, 1st Class Postage Prepaid, properly addressed to parties of record.

This the 25th day of April, 2014.

Charles A. Castle
Associate General Counsel

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	DIRECT TESTIMONY OF
Biennial Determination of Avoided Cost	)	KENDAL C. BOWMAN ON
Rates for Electric Utility Purchases from	)	BEHALF OF DUKE ENERGY
Qualifying Facilities	)	CAROLINAS, LLC AND DUKE
	)	ENERGY PROGRESS, INC.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kendal Crowder Bowman. My address is 410 South Wilmington Street, Raleigh, NC 27601.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed as Vice President Regulatory Affairs and Policy North Carolina for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP") (collectively the "Companies"), which are wholly owned subsidiaries of Duke Energy Corporation. DEP was previously named Carolina Power & Light, d/b/a Progress Energy Carolinas, Inc. The name change was effective April 29, 2013.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have a Bachelor of Science in Psychology from the University of Virginia and a Juris Doctor from Stetson University College of Law. My professional work experience began in 1997 when I began working as an attorney for Florida Power Corporation in St. Petersburg, Florida. In 1999, I joined Carolina Power & Light Company as an associate general counsel. Shortly after I joined Carolina Power & Light Company, it merged with Florida Power Corporation and became Progress Energy. After the close of that merger, I was Progress Energy's attorney for the Federal Energy Regulatory Commission ("FERC") matters for all regulated utilities and our unregulated merchant generation operations. Upon Progress Energy's exit from the unregulated merchant generation business in the early 2000's, I led Progress Energy's legal federal regulatory affairs group and was responsible for FERC legal, policy and compliance matters for Progress Energy Carolinas and Progress Energy Florida. In 2010, I transitioned from FERC work to State Regulatory legal work for Progress Energy Carolinas in both North Carolina and South Carolina. Following the merger between Duke Energy and Progress Energy (the "Merger"), I became Deputy General Counsel supporting all legal state regulatory functions for North Carolina. In February of 2013, I was named to my current role with Duke Energy.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES AS VICE PRESIDENT REGULATORY AFFAIRS AND POLICY FOR NORTH CAROLINA?

A. I am responsible for managing the Company's North Carolina regulatory matters and directing North Carolina energy policy for DEC and DEP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony generally summarizes the Companies' positions in this proceeding. I provide a brief summary of our testimony, which includes the witnesses that will provide testimony on our behalf. My testimony also provides a brief narrative on the history and requirements related to avoided cost rates and our experience with the implementation of the Public Utility Regulatory Policy Act of 1978 ("PURPA") in North Carolina. Finally, I also provide an overview of the Companies' recommended changes to the approved avoided cost calculation methodology to better align with the intent of PURPA and North Carolina law, more appropriately value the capacity and energy being provided by qualifying facilities ("QFs"), and restore necessary balance between the compensation provided to QFs and the costs imposed upon the Companies' customers.

Q. PLEASE DESCRIBE BRIEFLY THE DIRECT TESTIMONY THAT THE COMPANIES ARE PRESENTING IN THIS DOCKET.

A. In addition to my testimony, the Companies are presenting the direct testimony of Glen A. Snider, Director of Carolinas Resource Planning and Analytics for both companies and Lawrence Makovich, Vice President at IHS CERA. Mr. Snider will explain how the Companies currently develop their avoided cost rates and make specific recommendations for refinements and adjustments to the approved calculation methodology to improve the valuation of the energy and capacity being provided to the Companies, as well as the overall fairness to the Companies' customers. Mr. Makovich's expert testimony will address historical issues with the implementation of PURPA and provide specific recommendations regarding the appropriate calculation of avoided capacity costs, including which costs are appropriately included in such calculations and which costs are not. Further, Mr. Makovich will explain the need to balance the state implementation of PURPA with the ultimate cost to customers.

II. HISTORICAL OVERVIEW OF PURPA AND STATE RENEWABLE POLICY

Q. PLEASE PROVIDE A GENERAL OVERVIEW OF THE COMPANIES' PLANS WITH RESPECT TO THE INTEGRATION OF RENEWABLE RESOURCES INTO THEIR SYSTEMS IN THE CAROLINAS.

A. The Companies support the development of renewable generating resources and expect such resources to play an important role in the delivery of reliable, affordable and increasingly clean electric service to our customers in the future. Renewable resources are essential to the Companies' long term achievement of the State's policy goals established through its Renewable Energy and Energy Efficiency Portfolio Standard ("REPS"), enacted as part of Session Law 2007-397 ("Senate Bill 3"), as the Companies continue to plan for significant growth in the contribution of renewables to their respective long-term integrated resource plans ("IRPs"). Over the planning horizon of their most recently filed IRPs, the Companies are collectively planning for approximately 3000 megawatts ("MWs") of new renewable capacity to be added to their respective systems over the next fifteen years.

At the same time, the Companies are mindful that such development must be undertaken in a manner consistent with North Carolina's statutory and regulatory policy framework, requiring that the State's utilities plan and operate their systems prudently and reliably at "least cost" to their respective customers. Certain policy mandates, like REPS and PURPA, sometimes require that the Companies depart from least cost principles to comply with their respective requirements. However, these policy directives still aim to limit cost impacts to customers through specific cost constraints (i.e., the per account cost caps in REPS and the "avoided cost" ceiling in PURPA). The Companies adhere to those limits and principles as we plan and execute our renewable energy strategies for the benefit of our customers.

Q. WHAT ROLE DOES PURPA PLAY IN THE FEDERAL PUBLIC POLICY CONCERNING RENEWABLE RESOURCES AND THE COMPANIES' PLANS TO INTEGRATE THOSE RESOURCES INTO THEIR SYSTEMS?

A. PURPA is a key driver for the continued development of renewable resources throughout the United States, and it also acts as an important input into the Companies' planning for future generation needs. PURPA was enacted in 1978 largely in response to the 1970s energy crisis, and encompasses a policy to promote development of cogeneration and small power production facilities in the United States. These cogenerators and small power producers ("SPPs"), collectively called "Qualifying Facilities" or "QFs," were granted new rights under PURPA to interconnect to the electrical grid and to sell their electrical output in the wholesale marketplace. To this end, Section 210(a) of PURPA directed the Federal Energy Regulatory Commission ("FERC") to develop rules to implement PURPA's requirements. One of those rules was to require the incumbent electric utility to purchase electric energy produced by a QF. However, pursuant to FERC regulations, the rates for such purchases must be just and reasonable to the utility's electric consumers, in the public interest, and non-discriminatory to the QF. This mandate for just, reasonable, and non-discriminatory rates was enacted by Congress into a requirement that electric utilities offer to purchase the QF's output – either through a standard tariff rate or special contract (negotiated contract) – at the electric utility's "incremental cost of alternative electric energy," more generally referred to as the electric utility's "avoided cost." PURPA also designated state Public Service Commissions ("PSCs"), such as this Commission, as the appropriate bodies to determine avoided cost rates for the utilities over which a state's utilities commission has ratemaking authority.

Q. PLEASE PROVIDE THE COMMISSION WITH A HISTORICAL PERSPECTIVE ON PURPA'S REQUIREMENT THAT UTILITIES DEVELOP AVOIDED COST RATES.

A. Under PURPA, "incremental cost of alternative electric energy" is defined as "the cost to the electric utility of the electric energy which, but for the purchase from the QF, such utility would generate or purchase from another source." PURPA also mandates that no rule implementing PURPA shall provide for a rate that exceeds the incremental cost to the electric utility of alternative electric energy. However, PURPA does allow PSCs to authorize rates lower than avoided cost (if determined sufficient by FERC to encourage QFs), while also providing parameters with which electric utilities and state PSCs must comply in determining what constitutes a just, reasonable, and non-discriminatory avoided cost rate.

Q. TO DATE, HOW HAS NORTH CAROLINA IMPLEMENTED PURPA?

A. In 1979, the North Carolina General Assembly adopted the requirements of PURPA for SPP (hydroelectric generators no larger than 80 megawatts) in N.C. Gen. Stat. § 62-156, which provides that North Carolina's electric utilities shall offer rates to a QF SPP that shall not exceed, over the term of the purchased power contract, the utilities' avoided costs. In determining the utilities' avoided costs, N.C. Gen. Stat. § 62-156 provides that the Commission shall consider three factors over the term of the power contracts:

- The expected costs of the additional or existing generating capacity which could be displaced;
- The expected cost of fuel and other operating expenses of electric energy production that a utility would otherwise incur in generating or purchasing power from another source; and
- The expected security of the supply of fuel for the utilities' alternative power sources.

In addition, North Carolina's avoided cost statute provides that the "availability and reliability of power" shall also be considered in determining the rates to be paid by electric utilities for power purchased from a QF.

Q. CAN YOU FURTHER DESCRIBE THE RELATIONSHIP BETWEEN PURPA AND NORTH CAROLINA'S CURRENT RENEWABLE ENERGY POLICY?

A. In addition to implementing PURPA, North Carolina has provided state tax incentives to encourage the development of new renewable resources. These tax incentives allow investors in renewable resources to use up to thirty-five percent (35%) of their investment as a credit against their state income tax liability capped at $2.5 million per installation. Additionally, North Carolina established REPS through Senate Bill 3, which requires all electric providers in the State, over time, to use specific percentages of power from renewable sources to fulfill their service obligations. Senate Bill 3 also mandates specific minimum requirements with regard to certain types of renewable resources, including solar and animal waste generation. Thus, North Carolina has adopted an affirmative state policy that increases the role renewable resources will play in the State's energy future. However, and importantly, State policy makers balanced that goal with the need to ensure that customers continue to have access to low cost electric service. To that end, the General Assembly placed a cap on what electric providers were allowed to spend and charge to customers in fulfilling their REPS obligations.

It is in the area of customer protection that the interplay between Senate Bill 3 and PURPA is of most importance. Senate Bill 3's per account cost caps limit utility spending based upon those costs that are "incremental," which means "above avoided cost." In this way, the General Assembly intended to establish a limit on the costs in excess of the utility's traditional least cost power supply that its customers would have to bear in furtherance of the State's renewable resource policy. That customer protection mechanism only works, however, if avoided cost is truly set at levels which assure that customers are indifferent as to whether power is obtained from QFs or other sources.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THE CONNECTION BETWEEN PURPA AND SENATE BILL 3?

A. The General Assembly plainly intended to encourage the development of renewable resources, but only at reasonable cost to customers. Moreover, by establishing the cost caps based on an increment above avoided cost, the General Assembly clearly established a specific limit on the amounts that it expected customers to bear in paying for such development. The carefully crafted cost cap limitations established in Senate Bill 3 would be rendered meaningless if it can be easily circumvented by simply "redefining" avoided cost to encompass a host of new factors designed to increase payments to QFs. Thus, applying PURPA in the manner in which it is intended is important, not just to comply with PURPA itself, but also in the interest of maintaining the balance struck by Senate Bill 3 between the policy goals of encouraging renewable development and protecting customer interests.

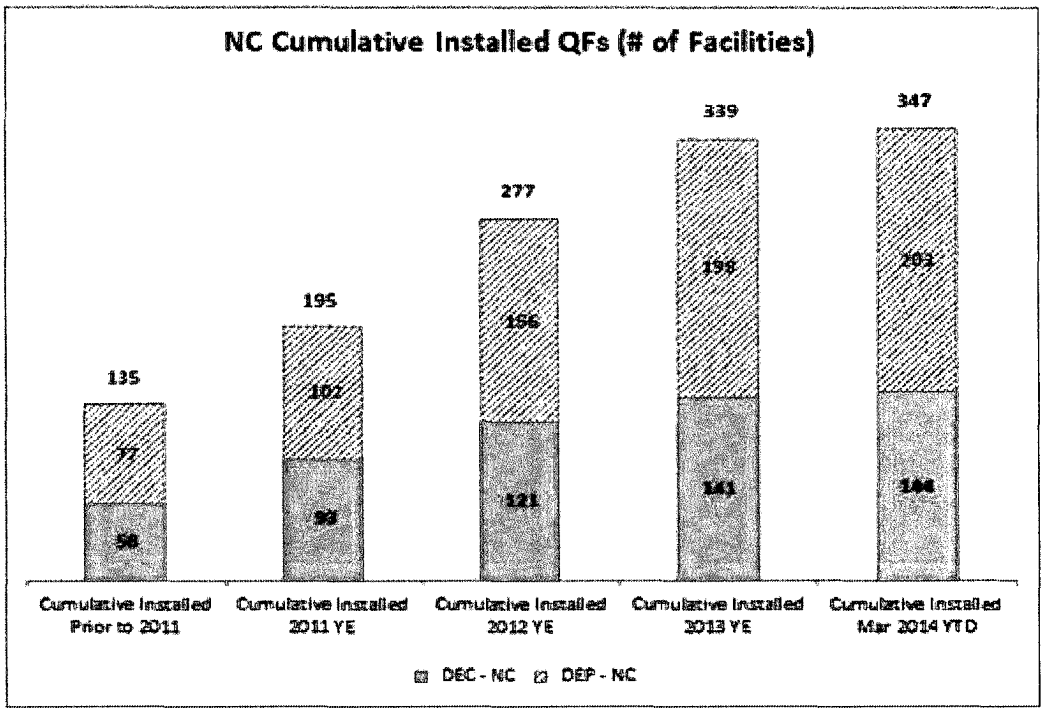
In essence, PURPA is simply a means of encouraging the development of ***efficient*** renewable resources by removing barriers to entry for such projects (i.e., by requiring utilities to purchase the output of such facilities). However, PURPA was not intended to be an unlimited source of subsidy for QFs. To the contrary, Congress made clear that rates to be paid QFs under PURPA must be capped at the utility's respective avoided cost, and be just and reasonable to the utility's customers. If applied properly, this would make utilities and their customers indifferent as to whether the utility purchases power from a QF or obtains it from an alternative source, which was clearly the underlying intent of PURPA.

It is also important to note that the avoided cost provisions operate as a ceiling, not an entitlement for QFs. As the U.S. Supreme Court has found, public service commissions ("PSCs") implementing PURPA may authorize payments to QFs that are below full avoided cost, if the lower rate is still sufficient to encourage QF development.[1] Under such a scenario, the cost savings produced by the below avoided cost rates would flow through to customers, not QF developers. The Companies are not suggesting the Commission adopt rates below fully avoided cost rates, but this permitted result underscores Congress' intent and the legal limitations of PURPA. PURPA is often described as a vehicle to encourage the growth of QFs, but that is only a limited part of the story. PURPA supports QF developers by ensuring that they can sell all of their output to utilities, but only if they can do so efficiently, i.e., at no incremental cost to the purchasing utility and its customers.

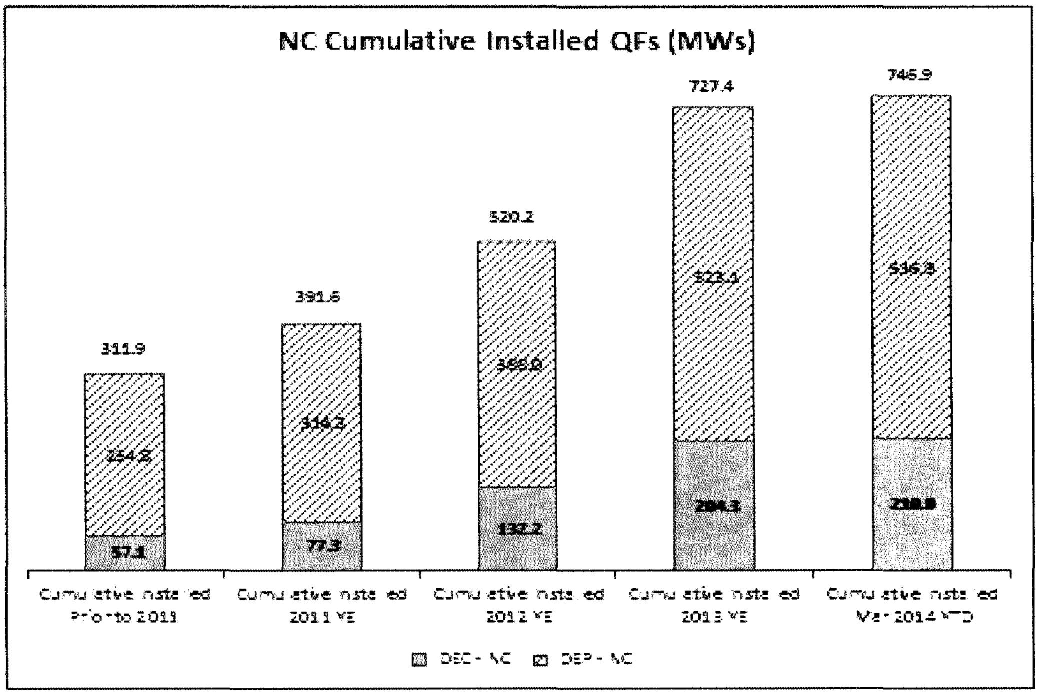
[1] *Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 416 (1983) ("It bears emphasizing that the full-avoided-cost rule is not as inflexible as might appear at first glance. [A]ny state regulatory authority ... may apply to [FERC] for a waiver of the rule. A waiver may be granted if the applicant demonstrates that a full-avoided-cost rate is unnecessary to encourage cogeneration and small power production. 18 C.F.R. § 292.403.").

Q. CAN YOU PROVIDE SOME BACKGROUND ON THE GROWTH OF QFS IN NORTH CAROLINA?

A. As the graph below demonstrates, the number of QFs in North Carolina contracting to produce and sell power to the Companies has increased significantly since 2011.



These installed QFs translate to the corresponding increase in the number of MWs from QFs that the Companies obtained and paid for through avoided cost rates, as shown in the following table:



Q. DO THE COMPANIES EXPECT THIS LEVEL OF QF GROWTH TO CONTINUE IN THE CAROLINAS?

A. It is very difficult to predict, but the Companies do not anticipate any slowing of the recent past and current growth rates. Indeed, nationally, a recent forecast by the United States Energy Information Administration "expects continued robust growth in solar electricity generation."[2] The following graph shows the increase in the number of North Carolina QFs in the Companies' interconnection queue since 2011 through March of this year.

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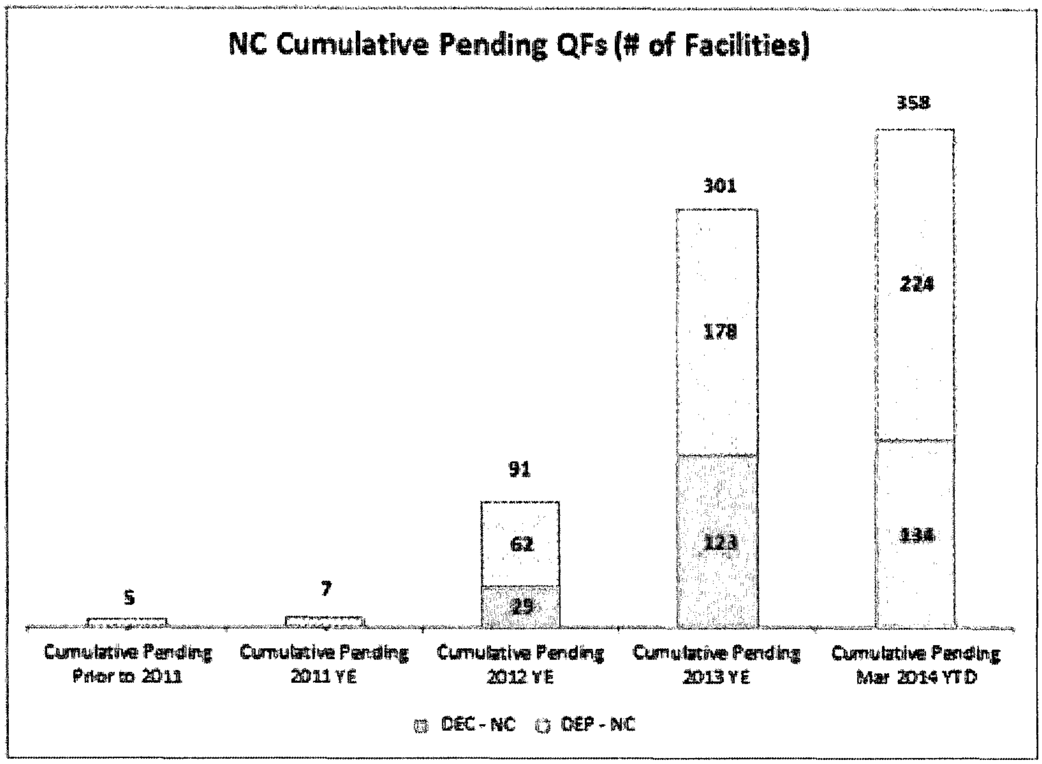
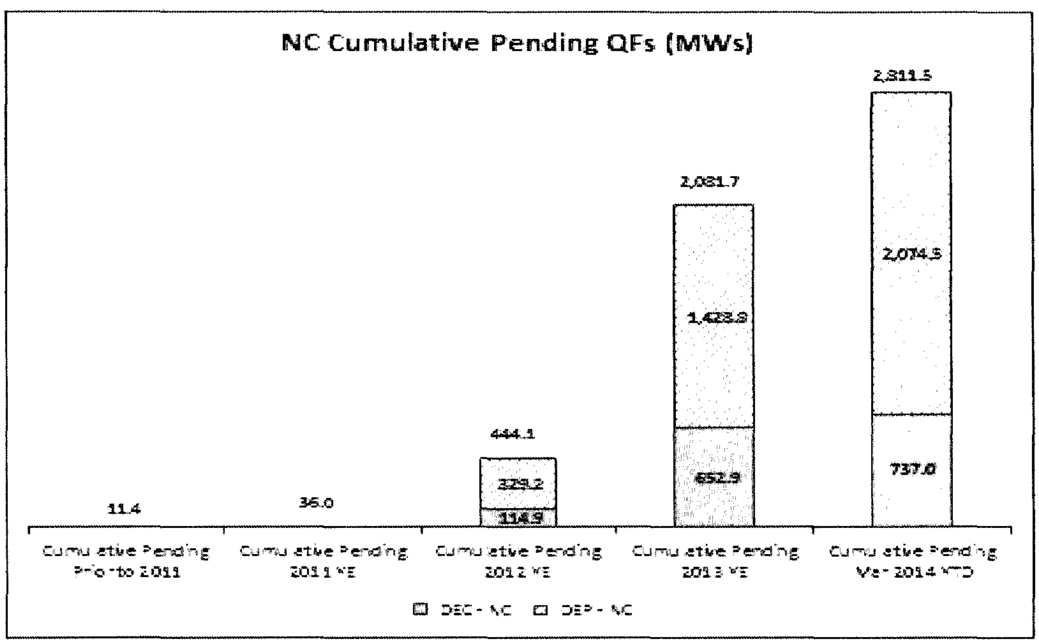
[2] Short-Term Energy and Summer Fuels Outlook (Released Apr. 18, 2014), *available at* http://www.eia.gov/forecasts/steo/report/renew_co2.cfm



As shown in the table below, the Companies estimate that the QF projects in the queue could result in an additional 2,800 MW of new capacity that would be eligible for avoided cost payments.



Q. HOW DOES THE ACTUAL AND PROJECTED GROWTH IN QF DEVELOPMENT IMPACT THE COMPANIES AND THEIR CUSTOMERS?

A. From an operational perspective, additions of a large amount of QF capacity, particularly non-dispatchable, intermittent capacity, will have an impact on the Companies' systems. From a customer's perspective, increasing amounts of QF capacity mean that a growing percentage of our customers' cost of electricity will be attributable to the power purchased from QFs. In theory, customers should be indifferent to such circumstances because of PURPA's avoided cost limit. In practice, however, customers may be economically disadvantaged if avoided cost rates do not accurately reflect the utilities' true cost of alternative power supply. When utilities compensate QFs at rates that exceed their avoided costs, it has a two-fold effect that harms customers. First, customers must bear the incremental costs from QFs that are higher than contemplated by both the letter and intent of PURPA. Second, these unjustifiable higher rates compound that effect by increasing QF growth as developers seek to take advantage of the avoided cost rates being offered above avoided costs.

III. RECOMMENDED CHANGES TO AVOIDED COST CALCULATION METHODOLOGY

Q. ARE THE COMPANIES RECOMMENDING CHANGES IN HOW THEY CALCULATE THEIR AVOIDED COST RATES?

A. Yes. As explained by Witness Snider, the peaker methodology, properly applied, allows the Companies to determine our avoided costs for purposes of calculating the avoided cost rates that our customers ultimately pay. There are concerns, however, that the current method for calculating avoided capacity and energy costs under the peaker method does not accurately reflect the value of the QFs' capacity and energy to our customers. Therefore, to adjust to the changing environment and to comply with the intent of PURPA, the Companies recommend that application of the peaker methodology be refined or modified to ensure that we fairly and appropriately capture and estimate our avoided costs. As outlined by Witness Snider, the Companies recommend several adjustments to the methodologies for calculating avoided capacity costs and energy costs.

A. <u>PROPOSED ELIGIBLE CAPACITY LIMIT MODIFICATION</u>

Q. DO THE COMPANIES PROPOSE THAT THE COMMISSION LOWER THE CAPACITY ELIGIBILITY LIMIT FOR STANDARD AVOIDED COST TARIFFS?

A. Yes. The Companies believe lowering the capacity threshold from 5 MW to 100 kW is appropriate and justified at this time given the state of the marketplace in North Carolina.

Q. HOW WILL LOWERING THE ELIGIBILITY FOR THE COMPANIES' STANDARD TARIFFS TO 100 KW IMPROVE THE AVOIDED COST PROCESS?

A. Currently, the Companies apply the peaker methodology to establish a standard avoided cost rate structure that is applied to all eligible QFs. In North Carolina, this applies to all renewable QFs of 5 MW or less and all non-renewable QFs of 3 MW or less. That definition of QFs eligible for the standard terms and rates covers a wide range of generation types and sizes. Generally, the peaker methodology is a reasonable approach to assessing a utility's avoided cost. However, using the peaker methodology to establish a single, standard rate cannot reasonably account for all of the differences between the variety of QFs currently eligible for the standard rate. Similarly, a single set of "standard" terms cannot address issues that may be specific to particular types of QFs or to specific QF projects. Conversely, in a bilateral negotiation the specific characteristics of a particular QF can be taken into consideration. The Commission has long acknowledged this in describing the types of factors that it expected that such negotiations should encompass, including (1) the availability of the QF during the utility's peak periods; (2) the expected reliability of the QF; (3) the utility's ability to dispatch the QF; (4) the coordination of the QF's scheduled outages with the utility's scheduled outages; and (5) the usefulness of the QF during system emergencies.[3] Accordingly, bilateral negotiations are better suited to accurately measure the avoided cost associated with a particular QF than are standard terms and rates.

[3] *See e.g.*, *Order Establishing Standard Rates and Contract Terms for Qualifying Facilities.* at 13-14, Docket No. E-100, Sub 53 (May 7, 1987). (enumerating appropriate issues for considerations and negotiation between the utility and the QF).

Prior to 1985, standard avoided cost tariffs from DEC and DEP were available to all QFs of up to 80 MWs. In Docket No. E-100, Sub 41A, the Commission established a 5 MW eligibility limit for the Companies', and other utilities', standard tariffs.[4] The small power production industry was in a nascent stage at that time. Consequently, the Commission established eligibility criteria that ensured that smaller project developers, who may not have the resources or expertise to negotiate with a utility, still had access to the standard terms and conditions. However, the industry has changed considerably in the past 30 years. The underlying public policy objectives are evolving and the technologies being utilized have changed. In today's environment, developers of even smaller projects tend to be well-experienced and sophisticated entities. Currently, in North Carolina, developers of QFs are routinely planning and developing projects both inside and outside the standard tariff parameters. As a result, the prior justification for the 5 MW threshold simply no longer exists. The current threshold has contributed to the increased level of planned capacity. This reduces the Companies' ability to manage growth in their systems on an orderly basis and reduces the Commission's ability to carry out its responsibility to assure that consumers have reliable power at the least possible cost.

In its Order No. 69, FERC also addressed the issue as to whether avoided cost rates should be set by negotiation when it established the rules

[4] *Order Establishing Levelized Rates and Cogeneration Power and Maintaining Interconnection and Wheeling Prices,* Docket No. E-100, Sub 41A (Jan. 22, 1985).

implementing PURPA. In that order, FERC acknowledged that standard one-size-fits-all avoided cost rates cannot account for the differences between QFs of various sizes and types. FERC, however, also noted the concern that smaller QFs could not bear the transactional costs of negotiating individualized bilateral rates. In balancing those issues, FERC concluded that it was reasonable to require the States implementing PURPA to make standard rates and terms available to QFs of 100 kW and smaller.[5]

In summary, lowering the eligibility limit for standard rates to 100 kW will, to a greater extent, allow rates offered to QFs to be based on a more precise assessment of the costs that particular QFs allow the purchasing utilities to avoid. It will help ensure that QF capacity is actually needed by the utility. At the same time, it will also ensure, consistent with PURPA and FERC regulations, that the standard rates are still available to smaller QFs that may not be able to justify the cost and effort of negotiating separate rates.

Q. HAVE ANY OTHER JURISDICTIONS TAKEN SIMILAR STEPS?

A. Yes. Idaho recently reduced the eligibility for standard rates for solar and wind QFs from 10 MW to 100 kW. Much like North Carolina, Idaho recently has seen a tremendous surge in new and proposed QFs. In particular, there has been significant growth of new and proposed wind QFs in Idaho. The Idaho Commission recognized that intermittent generation, such as wind resources, had particular characteristics that are distinct from other types of generation. Those distinguishing traits were even more pronounced as the

[5] Order No. 69, FERC Stats. & Regs., Regs. Preambles 1977-1981 P30, 128 at 52 (1980).

scale of such projects increase in size. The Idaho Commission, therefore, concluded that it was preferable to establish avoided cost rates for these types of QFs outside of the standard avoided cost process rather than developing a standard rate that would adequately address the divergent types and sizes of QFs.

Q. WILL QFS WITH A NAMEPLATE CAPACITY OF MORE THAN 100 KW STILL BE ENTITLED TO SELL POWER TO THE UTILITIES AT AVOIDED COST RATES?

A. Yes. The utilities will still be required to purchase the output of larger QFs, and the avoided cost requirements would still apply. The larger QFs, however, would receive avoided cost rates through bilateral negotiations with the purchasing utility and not through the applicable standard avoided cost tariff.

B. PROPOSED AVOIDED CAPACITY COST CALCULATION MODIFICATIONS

Q. DOES THE CURRENT APPROVED METHODOLOGY FOR CALCULATING AVOIDED CAPACITY COSTS OVERCOMPENSATE QFS?

A. Yes, we believe it does. The Companies' primary concerns with the current avoided capacity cost calculation are:

1. The lack of precision in the current standard tariffs in measuring a QF's capacity value to the purchasing utility; and

2. The application of an excessive Performance Adjustment Factor ("PAF").

The Companies' recommended changes to the approved avoided cost calculation methodology are primarily intended to address these deficiencies.

Q. HOW DO THE COMPANIES RECOMMEND THE METHODOLOGY FOR CALCULATING AVOIDED CAPACITY COST BE IMPROVED TO ENSURE FAIRNESS AND BALANCE TO PURPA IMPLEMENTATION IN NORTH CAROLINA?

A. Based on the specific concerns outlined above, and in the testimony of Witnesses Snider and Makovich, the Companies recommend the Commission approve the following changes to the standards and methodologies used to calculate avoided capacity cost rates for their standard tariffs:

1. Establish the parameters of key inputs used to calculate the installed cost of a combustion turbine ("CT") for purposes of calculating avoided capacity costs;
2. Calculate the capacity credits in the standard tariffs in a manner that takes into account the utility's relative need for generating capacity; and
3. Reduce the application of the PAF to avoided capacity credits to 1.05.

The Companies also recommend the Commission approve standard rates that pay capacity credits to QFs on a per-kilowatt-hour ("kWh") basis, consistent with current practice. These specific recommendations are intended to restore balance and fairness to the standard tariffs, such that QFs are appropriately compensated for the capacity they provide to the Companies and their customers, and the Companies' customers are only required to pay just and reasonable rates for QF power, consistent with the mandates of PURPA.

Q. WHY ARE THE COMPANIES PROPOSING TO ADJUST THE AVOIDED CAPACITY COST CALCULATION METHODOLOGY TO ACCOUNT FOR THE RELATIVE NEED FOR GENERATING CAPACITY?

A. One principal aspect of PURPA was, and remains, that QFs should be fairly and reasonably compensated for the incremental capacity and energy costs that, but for capacity and energy provided by the QF, the utility would be forced to incur to serve its customers. If the purchase of power from a QF does not, in part or in total, avoid the utility's need to incur incremental capacity and energy expense, then the QF should not be compensated for providing that benefit. PURPA was not intended to force utilities to pay for capacity that it does not otherwise need, and both Order No. 69 and subsequent FERC decisions have reinforced this point.[6] North Carolina law also contemplates this concept in that "a determination of the avoided energy costs to the utility shall include …the expected costs of the additional or

[6] *City of Ketchikan, Alaska, Copper Valley Electric Association, Inc., City of Petersburg, Alaska, City of Wrangell, Alaska*, 94 FERC 61, 293 (2001)("[w]hile the utility is legally obligated to purchase energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load"*) citing Order No. 69, supra note* 5 at 25-26.

existing generating capacity ***which could be displaced*** ..." N.C. Gen. Stat. § 62-156(b)(2)(emphasis added). This recommendation merely seeks to effectuate this concept in practice to allow avoided capacity credits provided to QFs to incorporate that actual capacity being avoided by the purchase of power from the QF.

Q. WHY ARE THE COMPANIES PROPOSING TO REDUCE THE PAF THAT HAS PREVIOUSLY BEEN APPLIED TO AVOIDED CAPACITY RATES?

A. As discussed in more detail by Witness Snider, the Companies are proposing to reduce the PAF to align its application better with the reliability of a natural gas combustion turbine ("CT"), the unit which the QF is presumed to avoid under the peaker methodology. The PAF is a multiplier applied to the avoided capacity rates paid to QFs to allow a QF to experience a reasonable amount of outage time without being penalized from the standpoint of the capacity payments it receives. The PAF was established because QFs only receive capacity payments for power that they deliver during on-peak hours. Because all generation is subject to outages, it is reasonable to assume that QFs, like other generation, will not run during 100% of on-peak hours. Thus, the PAF makes up for the fact that a QF might be unavailable during a peak period by increasing the capacity rate it is paid during the peak hours that it does operate. Currently, wind and solar QFs enjoy the benefit of a PAF of 1.2.

Given that the "avoided" resources are occasionally unavailable, it necessarily follows that QFs replacing such resources should not be penalized for experiencing the same level of unavailability typically experienced by the resources it is displacing. That logic works, however, only if the PAF is structured to put a QF on par with the resource it is replacing. In his testimony, Witness Snider provides the detailed rationale and recommendations for structuring the PAF to better reflect the CT that the QFs replace.

Q. WITNESS SNIDER RECOMMENDS A PAF OF 1.05. ARE THE COMPANIES PROPOSING TO REDUCE THE PAF TO 1.05 FOR ALL QFS?

A. No. The new PAF would only be applied prospectively to new QF contracts. The Companies understand that existing QFs have undertaken the development of facilities based on analysis of the terms of their contracts with the purchasing utility, which includes the PAF in force at the time the contract was executed. The Companies do not believe it would be reasonable to change the PAFs applicable to those contracts at this point.

Q. WOULD THIS CHANGE ALSO APPLY TO SMALL HYDROELECTRIC QFS?

A. With regard to small hydroelectric QFs, the Companies understand that these facilities occupy a special space in the State's energy policy. In fact, North Carolina Gen. Stat. § 62-156 codifies the State's policy to promote and support these facilities. Given this policy, the relatively small and finite amount of small hydroelectric capacity and expectation of little increase in such capacity in the future, the Companies are proposing to grandfather the current PAF of 2.0 for existing small hydroelectric facilities.

C. PROPOSED AVOIDED ENERGY COST CALCULATION MODIFICATIONS

Q. HOW SHOULD THE CALCULATION OF AVOIDED ENERGY COSTS BE ADJUSTED TO ENSURE THAT THE COMPANIES' CUSTOMERS ARE PAYING FOR THE TRUE VALUE OF THE QF ENERGY?

A. To better align our customers' payment for QF energy with the Companies' actual avoided costs for purchasing that energy, the Companies recommend three adjustments to the avoided energy calculation:

1. The recognition of specific, measurable integration costs associated with intermittent solar generation;
2. The adjustment for lost production cost benefits associated with the unit being avoided through the purchase of QF power; and
3. The elimination of multiple definitions of peak and off-peak hours within the tariff structure by eliminating the Companies' respective Option A schedules.

Witness Snider provides the detailed rationale and support for these recommendations in his testimony.

Q. WHY ARE THE COMPANIES SEEKING THESE SPECIFIC CHANGES TO THE AVOIDED ENERGY CALCULATION?

A. Generally, the cost-related adjustments on the integration of increasing volumes of solar and recognition of diminishing production cost benefits with greater QF penetration are intended to recognize components to the calculation that have not previously been captured. In large part, this is because, until recently, the Companies have not had significant enough QF penetration on their respective systems to readily identify and evaluate these issues. With the significant growth and increased role of QF power on our systems, the Companies believe it is important for the Commission to recognize and account for these costs in the calculation of avoided energy payments to QFs. As to the elimination of Option A schedules, the Companies believe that one set of peak and off-peak hours within the tariff structure is appropriate to represent its avoided costs accurately and send the appropriate price signals to QFs.

IV. CONCLUSION

Q. ARE THE ADJUSTMENTS PROPOSED BY THE COMPANIES DESIGNED TO ALLOW THE COMPANIES TO CAPTURE ITS FULL AVOIDED COSTS MORE ACCURATELY?

A. Yes. The Companies' proposed changes will allow them to better align their avoided cost rates with the value that the QFs provide to the Companies, and ultimately, our customers. The changes also update the Commission's policy to be more consistent with the current environment in which the utilities and QFs operate. Perhaps more significantly, the adjustments assure that the utilities' avoided cost rates are fully compliant with the underlying intent of

PURPA and the requirements of North Carolina law. This will assure that QFs are treated as both federal and state law intended and, at the same time, assure that consumers receive the protections also contemplated by those laws.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	DIRECT TESTIMONY OF
Biennial Determination of Avoided Cost	)	LAWRENCE MAKOVICH ON
Rates for Electric Utility Purchases from	)	BEHALF OF DUKE ENERGY
Qualifying Facilities	)	CAROLINAS, LLC AND DUKE
	)	ENERGY PROGRESS, INC.

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lawrence Makovich and my business address is 55 Cambridge Parkway, Cambridge, Massachusetts.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the firm IHS as Vice President and Chief Power Strategist. IHS is a company that provides data, analyses and strategic insights to businesses around the world with particular focus on the energy, automotive, chemical and defense industries, and I am an energy economist specializing in the analysis of the electric power industry.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have an undergraduate degree from Boston College where I majored in economics. My graduate degrees are both interdisciplinary and focused on economic policy. I earned a masters degree from the University of Chicago and a doctoral degree from the University of Massachusetts/Boston. I have been engaged in electric power research for over thirty-five years. In the past nine and one half years, I have worked for IHS after they acquired Cambridge Energy Research Associates ("CERA") in September of 2004. Prior to becoming part of IHS, I led the research effort focusing on the power industry at CERA since 1994. Prior to that, I was the senior economist for electric power research at DRI/McGraw Hill for thirteen and one half years. I began my career by spending two years with National Economic Research

Associates as a research associate involved in research used to support litigation in cases involving the electric power industry. A copy of my curriculum vitae is attached as Makovich Exhibit 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In my testimony, submitted on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, Inc. ("DEP"), I generally describe the primary issues that have arisen in the implementation of the Public Utility Regulatory Policy Act of 1978 ("PURPA") and my recommendations to correct these flaws to ensure a more balanced implementation path going forward.

Q. PLEASE SUMMARIZE THE MAJOR POINTS AND RECOMMENDATIONS OF YOUR TESTIMONY.

A. My testimony can be summarized as follows; since its enactment in 1978, PURPA has, in its implementation by state public service commissions ("PSCs"), produced certain economically inefficient consequences. Specifically, to date, PURPA implementation has (1) created inefficient price signals, and (2) encouraged incremental supply development regardless of utility need for additional supply. These mistakes are correctable and if they are corrected, the continued implementation of PURPA can function as the law intended and increase electric production efficiency in North Carolina. My specific recommendations are for the calculation of avoided costs to:

(1) Account for the relative need of the utility for incremental generating capacity;

(2) Account for the relative reliability and incremental value of the resource being delivered to the utility; and

(3) Include only the avoidable real incremental resource costs of utility power supply, and not societal costs.

I ultimately opine that setting PURPA rates appropriately by balancing the real resource cost of qualifying facility ("QF") development against the real avoidable resource cost of utilities will pace the size and timing of QF additions to increase electric production efficiency in North Carolina.

II. THE IMPLEMENTATION OF PURPA AND LESSONS LEARNED

Q: THIS PROCEEDING IS THE BIENNIAL DETERMINATION OF AVOIDED COSTS IN NORTH CAROLINA PURSUANT TO SECTION 210 OF PURPA. HAVE YOU STUDIED THE IMPLEMENTATION AND ECONOMIC IMPACTS OF PURPA?

A. Yes, I have extensively. As an example, I drafted a paper in 1985 entitled, The PURPA Problem, which identified, and proposed solutions to, certain economic inefficiencies inherent in the manner in which certain states had chosen to implement the policy.

Q. WHAT WAS THE PROBLEM WITH PURPA THAT YOU IDENTIFIED IN 1985?

A: The avoided cost provision of PURPA was intended to increase the efficiency of electric power production. To do this, PURPA relied on the avoided costs of existing utilities as the basis for a price signal to QFs to influence power supply decisions at the margin of the power production process. The economic logic was that this price signal should approximate the marginal cost of power supply. At that time, utilities were the primary source of power supply. The avoided cost price signal provided the economic incentive to add power supply from QFs that had an equal or lower marginal cost. In other words, a more efficient power supply was available if adding the QF production could displace more expensive utility power supply. The problem that I noted was two-fold; first, the utility avoided cost would generate an energy price that was higher than the efficient price signal, and second, the avoided capacity price was providing a signal to add supply during periods of time when new supply was not needed.

Q: WHAT CAUSED THE FIRST DIMENSION OF THE PURPA PROBLEM (THE INEFFICIENT PRICE SIGNAL)?

A: The first dimension of the PURPA problem existed because expanding power system supply to include QF electric production meant that the marginal cost of power supply was no longer going to reflect just the avoided cost of the utility, but instead would reflect the avoided cost of all existing suppliers—utilities plus QF suppliers. The short run marginal cost of power supply provides the efficient economic price signal. The utility's avoided cost would tend to be too high if the impact of non-utility supply on the marginal cost of power generation was ignored. This problem would lead to economic inefficiency because too much QF power would be added too quickly.

Q: WHAT CAUSED THE SECOND PART OF THE PURPA PROBLEM (ENCOURAGING ADDITIONAL SUPPLY IN THE ABSENCE OF NEED)?

A: The second part of the PURPA problem was that utility avoided costs included an avoided capacity price that was available regardless of whether the power system needed new capacity at the time or not. It is not efficient to build capacity before it is needed, and the price signal was encouraging too much QF capacity to be built too quickly.

Q: DID THESE PROBLEMS ACTUALLY ARISE?

A: Yes. Opening up power supply to non-utilities brought forth QFs, particularly cogeneration power supply, with marginal costs below that of the utility. This nonutility supply response was too much, too fast because it caused an accumulating power supply surplus in a number of power systems. Some power systems responded by placing a moratorium on additional QF development and eventually altered the avoided cost formula to reflect bidding from new suppliers (that reflected the marginal costs of non-utilities) or reflecting market clearing power prices determined by the intersection of the power system demand curve with the power system supply curve—a supply that was a summation of utility and non-utility marginal costs.

Q: WAS THIS A MISTAKE IN POLICY OR IN POLICY IMPLEMENTATION?

A: The latter. The PURPA problem was not a fatal flaw in the public policy design. PURPA opened up power supply to QFs and allowed the pursuit of a real opportunity to increase efficiency in the production of electricity in the U.S. As is usually the case, the devil is in the details, and implementing the avoided cost approach involved evolving the avoided cost determinations to set energy and capacity prices for QFs that were as economically efficient as possible.

Q: SHOULD A PURPA AVOIDED COST DETERMINATION INTERNALIZE THE SAME COSTS AS A UTILITY?

A: No. PURPA has a specific goal to augment existing power supply to increase the efficiency of the existing power production at the margin. Therefore, the determination of PURPA avoided costs should focus only on providing economic signals from avoided energy and capacity costs to QF decision making that affect QF power development and thus the efficiency of the existing power supply system. In contrast, utilities are concerned with more than simply increasing the efficiency of existing power supply at the margin. Utilities have to juggle numerous, often conflicting, goals. As a result, the utility power supply decision-making process internalizes a much broader set of costs and benefits than simply the single objective of improving existing power system efficiency at the margin.

The goal of PURPA was to use the avoided cost-based price signal to increase the efficiency of the existing power supply. The existing cost structure of utility power supply was taken as a given. The goal was not to make the decision process for QF power development identical to that of a utility and thus move QFs to replicate the power supply decisions and cost structures of a regulated utility.

Q: CAN YOU PROVIDE AN EXAMPLE OF COSTS AND BENEFITS THAT UTILITIES LIKE DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS INTERNALIZE THAT A QF TYPICALLY WOULD NOT?

A: Yes. The scale of utilities like DEC and DEP mean that these organizations are capable of moving research and development ahead through partnerships with government to build and demonstrate new technologies. For example, over the past several years, the U.S. federal government has announced that it would fund parts of advanced coal integrated gasification combined cycle generation and carbon capture and sequestration projects. Developing such new technology is more risky and more costly than building conventional power plants. However, in these cases, the potential benefits of advancing the current state of technology overrode the one-dimensional criteria of improving economic efficiency at the margin in the existing power supply mix.

III. PURPA IMPLEMENTATION GOING FORWARD

Q: ARE THE LESSONS FROM "THE PURPA PROBLEM" APPLICABLE TO SETTING AVOIDED COST PRICES FOR QF RESOURCE DEVELOPMENT IN NORTH CAROLINA IN THE FUTURE?

A: Yes, avoided cost determination influences the size and pace of QF power additions in North Carolina, and PURPA avoided cost based prices affect the efficiency of overall power production.

Q: DOES THE DETERMINATION OF BOTH THE AVOIDED COST OF ENERGY AND THE AVOIDED COST OF CAPACITY AFFECT THE SIZE AND PACE OF QF DEVELOPMENT?

A: Yes, on the energy side, avoided costs reflect the short run marginal cost of power production—the costs of fuel and operation and maintenance expenses that were directly linked to producing more or less electricity with the existing generation mix at any point in time. Similarly, on the capacity side, power production needs to give consumers the electricity that they want whenever they want it. To do this, power production involves more than just producing electric energy. In particular, providing power to consumers at all times requires enough capacity at the right times to meet the maximum consumer demand with a reserve of productive capacity to insure the level of reliability that consumers want. In North Carolina, PURPA avoided capacity costs typically reflect the levelized cost of adding a peaking power plant into the generating mix; this is typically referred to as the "peaker methodology."

Q: **DO THE AVOIDED COSTS OF ENERGY AND CAPACITY CHANGE THROUGH TIME?**

A: Yes, the short run marginal costs of power supply change due to changes in the level of power demand, the installed capacity mix, delivered fuel costs and operating costs. Similarly, the need for additional capacity changes as expectations regarding future reserve margins and new power plant costs and lead times change. As a result, economic efficiency requires a periodic update of avoided cost prices to reflect expected short run marginal costs of power production and to reflect the latest costs, needs and timing of capacity development.

A. <u>APPROPRIATE VALUATION OF QF CAPACITY</u>

Q: **DOES THE VALUE OF CAPACITY HAVE A TIME DIMENSION?**

A: Yes. The value of capacity is low the majority of the time because the aggregate consumer level of demand is typically low compared to the existing capacity available to operate at that point in time. On the other hand, the value of capacity is high when available capacity is just sufficient to meet aggregate consumer demands at a given point in time with the desired reserve margin. In this case, the value of capacity reflects its replacement cost because existing capacity is not an available alternative.

Q: **WHAT IS THE ECONOMICALLY EFFICIENT WAY TO PAY SOLAR POWER RESOURCES FOR THEIR CAPACITY?**

A: Like any other source of capacity, solar capacity should be paid for the net dependable capability it provides ***when the power system needs capacity***.

Assessing the net dependable capability of solar is complex because solar capacity is an intermittent, non-dispatchable resource that does not possess the same operating characteristics as conventional power generation technologies. Thus, solar resources' value to enhancing grid reliability must be assessed within the context of its technical and economic operational characteristics.

Q: IS THERE A CONSENSUS ON THE CAPACITY VALUE OF SOLAR RESOURCES TO A POWER SYSTEM?

A: No, assessments of the capacity value solar resources produce a wide range of estimates, as shown in Table 1. The metric is the percentage value of capacity compared to the capacity value of a conventional natural gas combustion turbine ("CT") power plant.

TABLE 1:

Range of capacity values assigned to solar in the literature	
State	Percentage of Comparable Peak Resource's Rating
Texas	40%-60%
Arizona	50%-70%
Mid-Atlantic	28%-45%
New England	22%-60%

Source: IHS

All of the assessments of the value of solar capacity find that solar power resources provide less capacity value compared to their potential maximum capacity capability when compared to a conventional natural gas CT power plant.

Q: TAKING THIS INTO ACCOUNT, SHOULD THE CAPACITY VALUE OF SOLAR RESOURCES REFLECT THE AVERAGE CAPABILITY OF SOLAR AT ANY POINT IN TIME?

A: No, average availability at time of peak is a simplistic answer to a complicated question. Although it is necessary to assess the expected value of solar net dependable capacity at the times of power system capacity needs, it is also necessary to assess the variance of net dependable solar capacity.

Q: HOW DOES THE VARIANCE OF SOLAR CAPACITY AVAILABILITY AFFECT ITS CAPACITY VALUE?

A: A simple example can illustrate the relationship between the average net dependable value of solar and the variance of solar net dependable capacity at a given point in time.

Table 2 illustrates a simple example of a power system involving just five time periods when supply must meet a 1 MW level of aggregate demand from consumers. The objective of a reliability assessment is to reduce the probability of a loss of electric load to a cost effective level. In many cases, an industry benchmark is to reach a probability of losing load of one day in ten years. Suppose that a stochastic assessment of conventional generation in a power portfolio typically finds that a reserve margin of 15% delivers the targeted reliability level of an expected one day in ten years outage outcome when employing conventional generating resources.

Now suppose solar capacity is substituted for conventional generation based on its average net dependable value. Since sunlight conditions vary, Column 1 varies the output the 1 MW of nameplate solar power capacity and reports a net dependable rating for the solar resource. The average net dependable value is 0.5 of the solar nameplate capacity. In addition, the net dependable rating of the solar resource varies from 0.3 to 0.6 around this expected value of 0.5. Using a capacity credit based on this average availability leads to the conclusion that one MW of solar nameplate capacity can provide the equivalent net dependable capacity of 0.5 MW of conventional generating technologies. From this perspective, 0.65 of conventional generation is needed in addition to the solar capacity in order to meet demand with a 15 percent reserve margin.

In this simple example, the capacity mix including solar resources fails to deliver the desired level of reliability the way that a fully conventional power supply mix would. Column two shows the actual net dependable capacity available in each time period and indicates that resources will be insufficient to meet demand in one time period and therefore, the associated loss of load probability is 20 percent. The implication is clear--a reliability assessment has to incorporate not only the expected value of solar (average availability at time of peak demand), but also must incorporate the variability of the intermittent resource at time of peak.

TABLE 2: RELIABILITY OF MEETING 1 MW OF DEMAND

Time Period	Output of 1 MW solar	Conventional plus solar capacity	Loss of load probability (percent)
1	0.5	1.15	0
2	0.6	1.25	0
3	0.3	.95	100
4	0.6	1.25	0
5	0.5	1.15	0
Expected Value	0.5	1.15	20

Reliability assessments typically involve such detailed approaches when evaluating the capacity needed in a power system. Such assessments are complex, but more simplistic approaches can be unreliable.

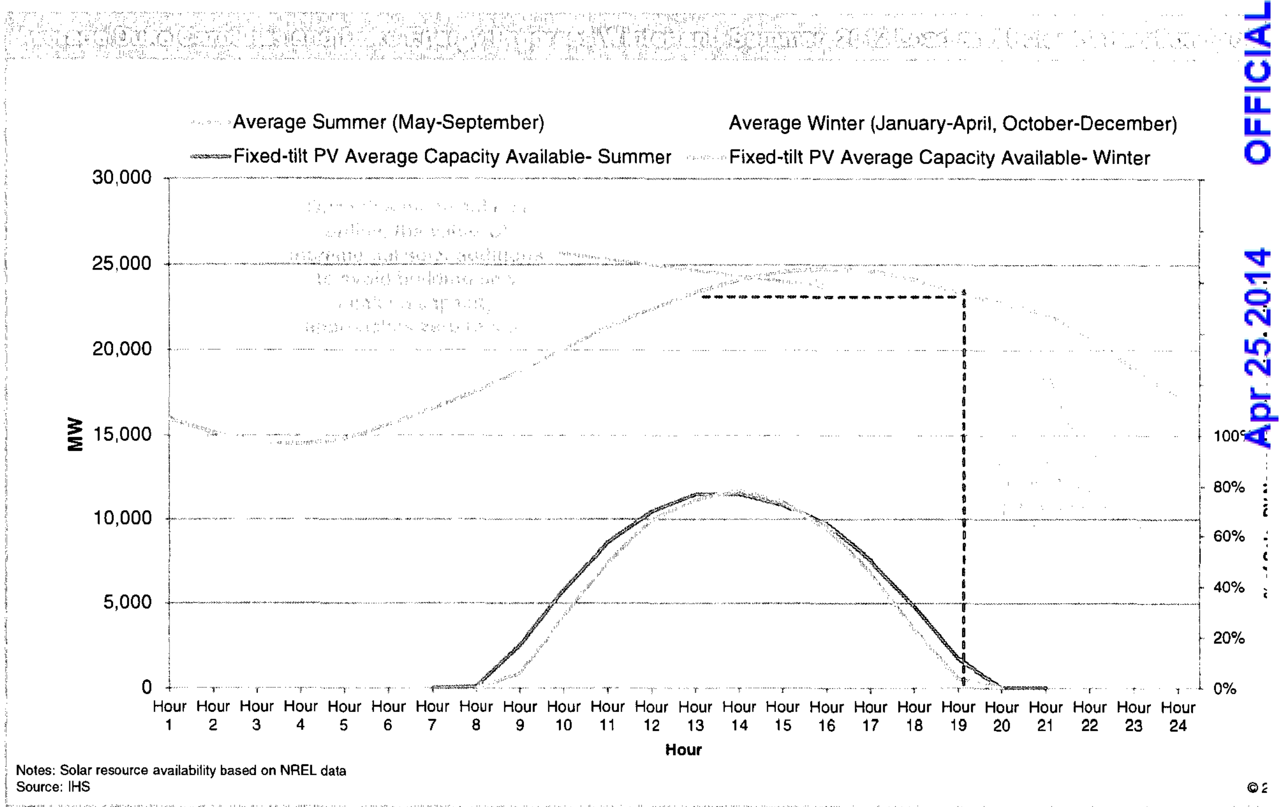
Q: **DO YOU EXPECT THAT A RELIABILITY ASSESSMENT INCORPORATING THE COMPLEX STOCHASTIC LINKAGES BETWEEN ADDING SOLAR CAPACITY AND THE EFFECT ON RELIABILITY WILL PRODUCE A POSITIVE NET DEPENDABLE CAPACITY VALUE FOR SOLAR RESOURCES?**

A: Yes, I expect the capacity value of introducing solar resources into a generation mix will be positive, but diminishing as the penetration of solar resources in the capacity mix increases.

Q: **WHY DO YOU EXPECT THAT THE VALUE OF SOLAR CAPACITY WILL EVENTUALLY DIMINISH IN A CAPACITY MIX?**

A: Once a substantial proportion of peak capacity is met with solar, the capacity value of incremental solar capacity diminishes significantly because the critical reliability challenge shifts to the evening peak demand levels. For example, the 2012 hourly aggregate load profile of DEC and DEP indicates that the peak demand during sunlight hours is roughly 3,000 MW higher than the demand without sunlight at 8pm, as shown in Figure 1. Adding more net dependable solar beyond this difference provides no capacity value to meet the critical peak demand that is now determined as the maximum net load (aggregate consumer demands less solar output).

FIGURE 1:



Q: WHAT ARE THE EFFICIENCY IMPLICATIONS OF THE DIMINISHING CAPACITY VALUE OF SOLAR IN A CAPACITY MIX?

A: This means that any capacity value assigned to solar should take into account the amount of solar already installed relative to the net loads. Doing so will allow a more efficient pacing of the amount and timing of solar development. Efficiency gains arise when the costs of solar additions are properly balanced against the benefits—avoided energy production costs and power system capacity value—through time.

Q. SO, IN ESSENCE, THE UTILITY SHOULD NOT BE FORCED TO PAY FOR CAPACITY IT DOES NOT IN FACT NEED?

A. That is correct. The objective is to provide consumers with efficient power supply, and it is inefficient to pay someone to add capacity before it is needed.

Q. YOUR EXAMPLE FOCUSES ON SOLAR RESOURCES. IS THIS PRINCIPLE EQUALLY APPLICABLE TO OTHER QF RESOURCES?

A. Yes, it is.

B. INCLUSION OF SOCIETAL COSTS IN PURPA RATES

Q. PURPA IMPLEMENTATION HAS FOCUSED ON COMPENSATING QFS AT NO MORE THAN THE PURCHASING UTILITY'S AVOIDED COSTS, AND TRADITIONALLY THOSE AVOIDED COSTS HAVE INCLUDED THE COSTS RELATED TO THE INCREMENTAL CAPACITY AND ENERGY THAT THE UTILITY MAY AVOID BY PURCHASING FROM THE QF. IS IT APPROPRIATE TO INCLUDE OTHER TYPES OF COST IN THIS EQUATION?

A. The appropriate types of costs to include in a PURPA rate are determined by the power production efficiency criteria. Power production efficiency requires balancing the real resource incremental cost of QF power supply against the avoidable real incremental resource cost of utility power supply. These costs reflect the value of the scarce inputs used to produce power—fuel and variable O&M for energy production and the land, labor and capital for capacity additions. Including a cost in the PURPA rate that does not reflect an avoidable real resource cost would lead to economic inefficiency in power production.

Q: WHAT ARE "SOCIETAL COSTS"?

A: The term "societal cost" is typically used to describe a cost that is not being internalized in a decision making process. For example, suppose a power system needs to increase supply and can do so with either one of two options available at the same costs but with different associated carbon dioxide ("CO2") emissions levels. In this case, the power supplier is comparing equivalent costs that do not incorporate the costs of climate change to the broader global society due to an incremental increase in atmospheric concentrations of CO2.

Q: SHOULD RATES CALCULATED TO COMPENSATE QFS UNDER PURPA INCLUDE ANY SOCIETAL COSTS?

A. No, such "societal costs" do not fit into that equation, nor should they. The PURPA avoided cost delivers electric production efficiency by providing a price signal to balance the avoidable marginal costs of the existing power supply with the marginal costs internalized by a QF power supplier.

Q: SHOULD THE PURPA AVOIDED ENERGY COST INTERNALIZE THE COST OF INCREMENTAL CO2 EMISSIONS THAT DUKE USES IN ITS INTEGRATED RESOURCE PLANNING PROCESS?

A: No. To achieve efficiency goals in North Carolina power production, the avoided costs determination in North Carolina should reflect actual avoided resource costs. The CO2 price employed in integrated resource planning is not a cost estimate of avoided environmental damage to North Carolina. Instead, the price of CO_2 emissions is a politically determined price designed to influence the decision making in specific applications.

Q: ARE THESE SOCIETAL COSTS OR IMPACTS RELATED TO CO2 EMISSIONS BEING AVOIDED THROUGH INCREASED SOLAR OR QF DEVELOPMENT IN NORTH CAROLINA EVEN KNOWN AT THIS TIME?

A: No, there is not a consensus on the actual CO_2 displacement of solar generation in North Carolina. An accurate quantification of the avoided generation emission profiles must be done to determine the environmental costs and benefits of solar relative to fossil fueled electric generation. Analysis of an integrated power system can reasonably quantify the amount of emissions likely to be displaced. Such analyses identify the marginal generating units in each hour and the associated emissions profile in a power system. Any analysis of displaced marginal generation must account for a variety of factors: the level of electricity demand throughout the day, the economic dispatch order of resources that will be used meet that demand at that point in time, the amount of installed solar capacity, and the generation profile of the solar capacity at each point in time. The economic dispatch order of the resources will be determined by the generating unit's variable costs, which include the plant's efficiency and input fuel costs. The generation profile of the solar resource will be determined by the time of day, the season, the location of the resource, and the type of solar resource.

Q: DO THE CURRENTLY AVAILABLE STUDIES ON CARBON DISPLACEMENT PROVIDE AN ACCURATE AND RELIABLE ESTIMATE OF AVOIDED EMISSIONS FROM INCREASED SOLAR GENERATION IN NORTH CAROLINA?

A: No. The currently available estimates of pollution costs per kWh are not based on specific power system analyses but rely instead on a simplified generic generation displacement estimate. Studies that specifically address North Carolina provide examples of applying generic plant emission profiles. The 2010 "Working with the Sun Study" produced by Environment North Carolina Research and Policy Institute ("2010 ENCRP Study") stated:

> *On average, each megawatt-hour of electricity generated in North Carolina produces 1,331 pounds of carbon dioxide, the leading pollutant driving global warming.*

The study projected avoided emissions from additional solar power development beyond CO2 emissions. The study stated:

> *By displacing coal-fired power, solar power can help to prevent mercury contamination. In the year 2030, solar power could annually prevent the emission of 410 pounds of highly toxic mercury pollution. This amount is significant as just 1/70th of a teaspoon of mercury can make the fish in a 25-acre lake unsafe to eat.*

By displacing the need for electricity from traditional power plants in North Carolina and the surrounding region, solar power could reduce the emission of soot-forming sulfur dioxide into the atmosphere.

The emission displacement estimates from the 2010 ENCRP Study used the actual emissions rates in 2005 that were published by the U.S. Environmental Protection Agency in 2009. The study's extrapolation of Duke Energy's 2005 emission rates through 2030 no doubt resulted in a much higher projection of avoided emissions from a large build-out of solar PV than will actually be the case. The generation mix in North Carolina has changed significantly since 2005 and will continue to evolve in the years ahead. In particular, significant reductions in Duke Energy's air emissions have occurred since 2005 as a result of North Carolina Clean Smokestacks Law. In the years ahead, Duke Energy will no longer operate coal-fired power plants without conventional pollution control technologies.

Further evidence of this shift comes from the 2013 Crossborder Energy North Carolina solar study that did not use a coal-fired power plant to estimate the emission associated with energy production displaced by solar generation, but instead used a generic combined cycle natural gas-fired power plant and its emission profile. The rationale was that this generic plant more closely approximated the emissions profile at the margin revealed in the most recent avoided cost proceeding in North Carolina. The estimate of avoided CO2 emissions was more than halved when a natural gas-fired power plant emissions profile is used instead of a coal-fired power plant emissions profile.

Q: SHOULD AVOIDED COSTS INTERNALIZE AN ADDITIONAL COST FOR AVOIDED CONVENTIONAL POLLUTANTS?

A: No. Public policies other than PURPA have weighed the costs and benefits of managing conventional pollutants. In each case, public policies limited, but did not eliminate the release of conventional pollutants. This makes economic sense because it is seldom the case that eliminating all pollution is efficient. Policy targets typically reflect balancing of the trade-off between the incremental benefits of pollution reduction to its incremental costs. The cap-and-trade approach to SO2 emission control put a price on emissions. As a result, these marginal costs of SO2 emission control already affect the marginal cost of power generation. Therefore, the short run marginal costs of power production already reflect the short run marginal costs of SO2 pollution reduction. In this case, if avoided costs already reflect the short run marginal costs of power production, then adding a conventional pollution charge to the avoided cost will charge consumers twice for the marginal costs of conventional pollutant reduction.

C. SIGNPOSTS AND THE IMPORTANCE OF BALANCE IN IMPLEMENTING PURPA

Q. YOU ALLUDED TO THIS EARLIER, BUT HAS RECENT QF DEVELOPMENT FOCUSED ON ANY PARTICULAR TYPES OF RESOURCES?

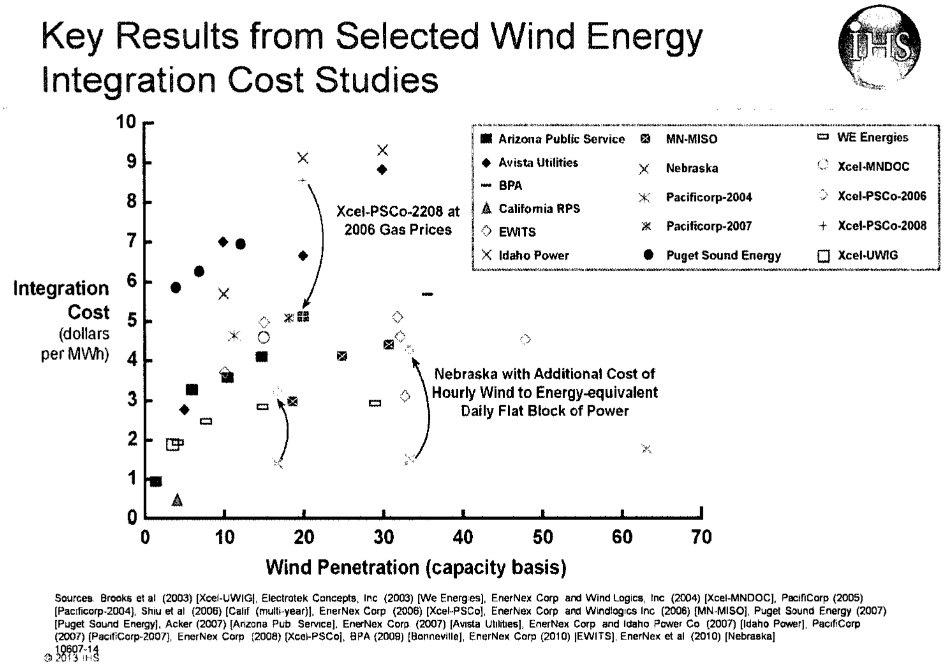
A. Yes, current trends are leading to QF development of intermittent wind and solar power supply resources.

Q. DOES INTEGRATING INTERMITTENT RENEWABLE POWER IMPOSE COSTS ON POWER SYSTEM OPERATIONS?

A. Yes, it does. Integrating intermittent renewable power imposes additional costs on power system operations. As levels of solar PV generation increase on a power system, it can cause cycling of different fossil fuel power plants (usually natural gas but sometimes coal) and require ramping of these resources. Both cycling and ramping tend to increase operating costs. Most power plants do not operate as efficiently when they are running under a partial rather than full load. As a result, there can be higher heat rates (fuel use per kWh produced) and less productive efficiency during these partial load periods. Adding too much solar power too fast into a generation mix exacerbates the reduction in the cost effectiveness of power supply.

To quantify potential increases in production costs from cycling and ramping accurately, it is necessary to determine which plants are cycling or ramping due to the integration of additional solar generation. This will vary with the utility system, depending upon what type of generating plants that are used to accommodate fluctuations in PV output. Figure 2 shows the results of a number of renewable integration studies that show not only that intermittent renewable power imposes costs, but that these integration costs increase as the penetration of intermittent generation increases.

FIGURE 2:



More specific to DEC and DEP, Witness Glen Snider includes as an exhibit to his testimony the solar integration study performed by Pacific Northwest National Laboratory, and completed in March 2014, which made similar findings with respect to the operational impacts of integrating increasing amounts of intermittent solar resources into the Companies' systems in the Carolinas.

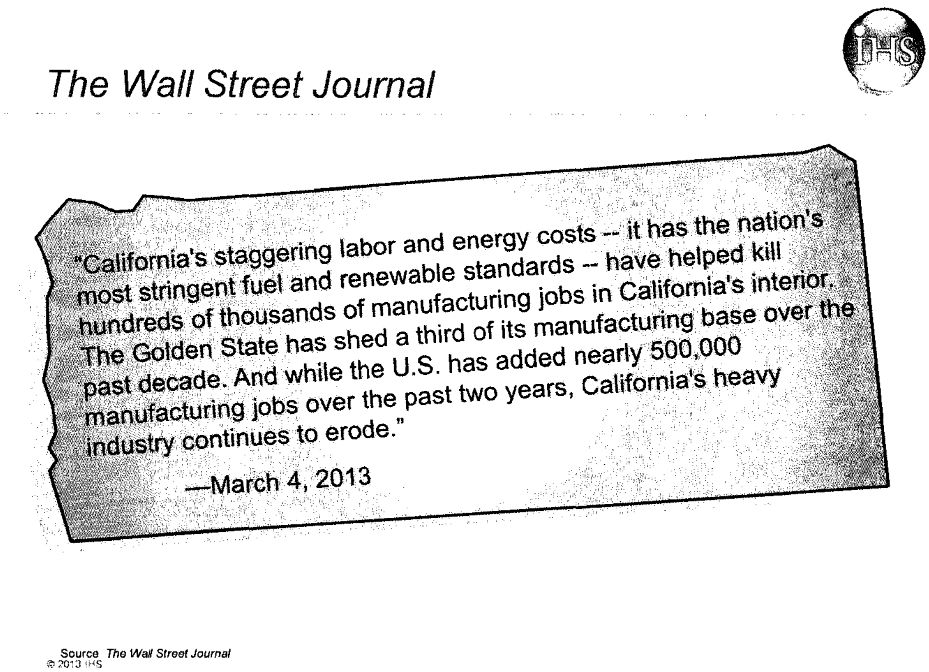
Q. DO THE INCREMENTAL COSTS RELATED TO IMPLEMENTATION OF RENEWABLE ENERGY POLICIES AND TO THE INTEGRATION OF INTERMITTENT RESOURCES IMPACT RETAIL POWER PRICES?

A. Yes, they do. The higher costs of QF power and the associated added integration costs put upward pressure on retail power prices. Power prices are one of a number of factors that determine the industrial competitiveness of a region. This means that as the price of electricity increases, industrial competitiveness declines and some jobs are lost. Therefore, the jobs impact of solar development needs to be analysed as a net jobs impact.

Relative industrial energy costs matter in decisions regarding where companies manufacture goods, and an increase in industrial retail prices impacts jobs in North Carolina just like any other state. These impacts are an important consideration. Since the beginning of the recovery from the financial crisis in 2009, the average annual economic growth in states with the 15^{th} lowest industrial electricity prices has been 0.6 percentage points higher than states with the 15^{th} highest industrial electricity prices. Since mid-2009, when the current economic recovery began, the 10 states with the lowest power prices gained 73,000 manufacturing jobs, whereas the 10 states with the highest power prices lost 69,000 manufacturing jobs.

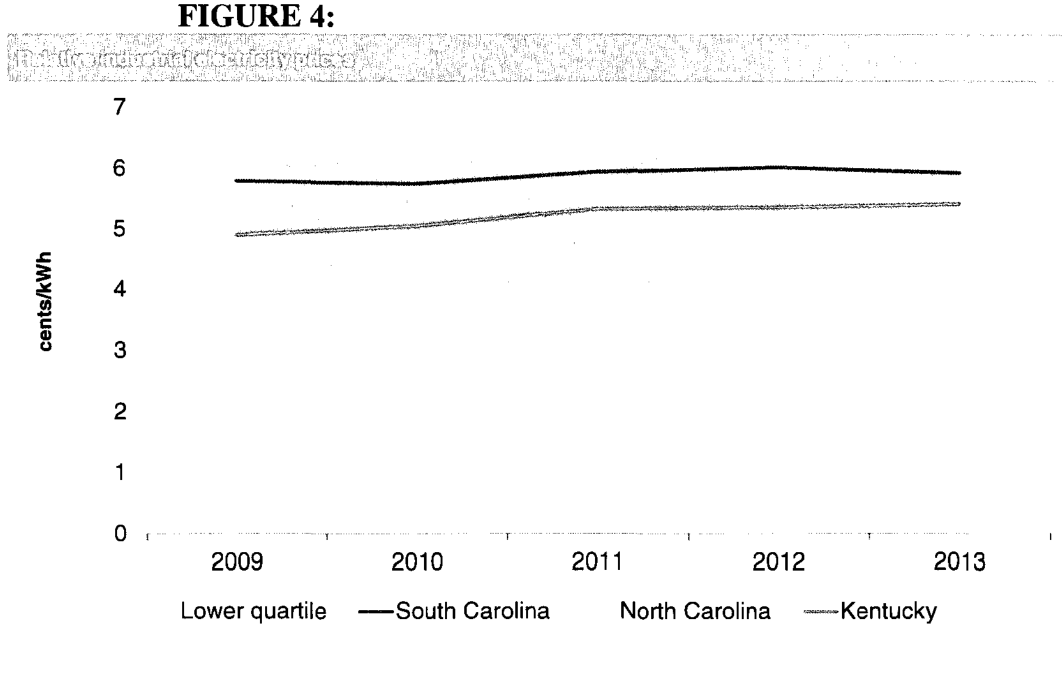
California's renewable policy is one of the reasons it has among the highest power prices in the U.S. California is a useful case study of jobs loss due to the costs associated with its renewables policies, as pointed out by the Wall Street Journal in Figure 3.

FIGURE 3:



North Carolina currently has some of the lowest industrial electricity prices in the U.S. Figure 4 shows that average industrial prices in North Carolina are close to the lower quartile in the U.S. at 6.3 cents/kWh.

FIGURE 4:

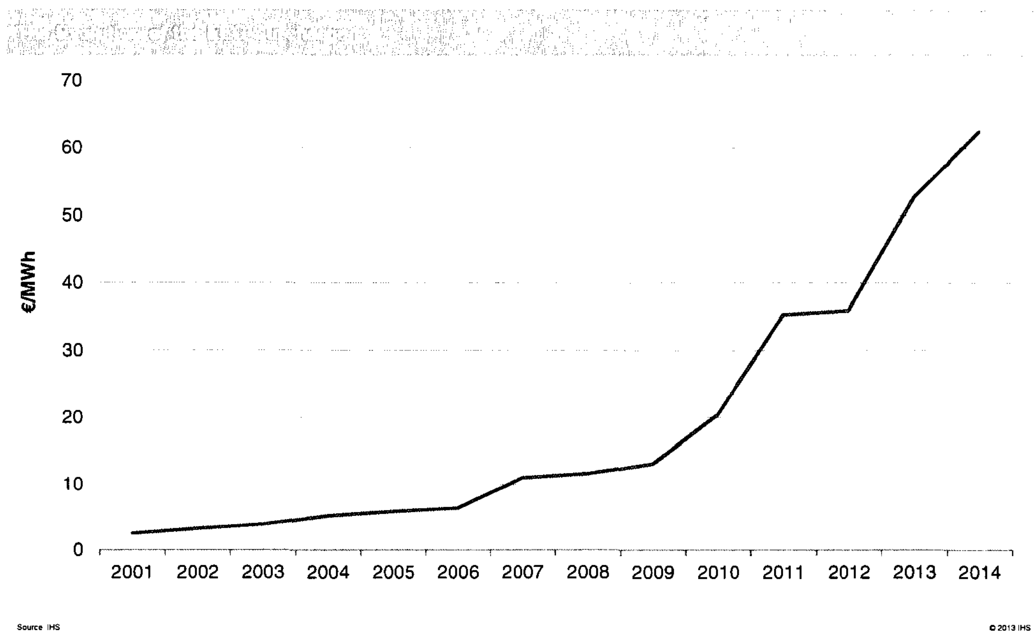


Three solar studies (NYSERDA, RTI / La capra, and NREL) attempt to account for any of the feedback effects caused by the solar costs increasing power prices. These feedback effects are identified as a key driver of the overall negative effects reported by NYSERDA,

In terms of the total impact of the Base case PV deployment on the economy, there will be no net-job gain, in fact, modeling showed a net job loss of 750 jobs per year because of the impact of increased electricity rates. Gross state product (GSP) would be reduced by $3 billion between 2013 and 2049, representing a small annual decrease in GSP of less than 0.1%.

North Carolina competes in a global economy, and other countries also provide important policy lessons. Germany provides a classic example of the adverse effects that a rapid build out of renewables can have on the wider economy. Germany is Europe's largest power system and a leader in shaping EU energy policy. Germany added too much renewable power too fast to its power system and incurred a significant cost. By the end of 2013, total renewable support payments reached €52/MWh in Germany – nearly 40% were the costs of solar (see figure 5). The total size of support payments was over 130% of the wholesale power price.

FIGURE 5:



Germany's average electricity price level was 21% above the international benchmark in 2008, which widened to 40% in 2013. German energy policy responded by trying to protect industrial competitiveness through rebates to energy-intensive industries. However inter-linkages within the economy mean that the renewable support increases the cost of smaller companies in the supply chain as well as other sectors of the economy. As a result of this growing price differential, Germany's manufacturing sector suffered net export losses that increased from 2008 to 2011 and climbed again in 2013. IHS estimates that the net export losses directly attributed to the electricity price differential were €15 billion in 2013, triple 2009's losses, and totaled €52 billion for the six year period 2008-13.

Other studies into the European experience conclude that the feedback effect of the aggressive renewables strategies have produced a net cost to the economy. In Spain for example, a study by the Rey Juan Carlos University of Madrid found that 2.2 jobs were lost for every renewable job created. The study reports that higher electricity prices used to create renewables jobs such as construction, fabrication and installation adversely affected employment in sectors such as metallurgy, mining, beverage, tobacco and food processing industries.

Q. WAS PURPA INTENDED TO INCREASE RETAIL POWER PRICES?

A. No. If the goal was to increase the efficiency of power production, then achieving this ought to lower costs and thus also lower retail power prices.

V. CONCLUSION

Q. DOES APPROPRIATE IMPLEMENTATION OF PURPA REQUIRE THE COMMISSION ACCOUNT FOR THE ULTIMATE IMPACT ON CUSTOMERS WHEN SETTING RATES FOR QF PURCHASES?

A. Yes, the goal of PURPA was to increase the efficiency of power production by providing the proper economic signal to QF power development. The goal was not to develop as much QF power as quickly as possible.

Q. WILL SUCH BALANCING OF THE REASONABLENESS TO CUSTOMERS HELP TO AVOID THE POTENTIAL IMPACT OF QF GROWTH IN NORTH CAROLINA?

A. Yes, setting PURPA rates appropriately by balancing the real resource cost of QF development against the real avoidable resource cost of utilities will pace the size and timing of QF additions to increase electric production efficiency in North Carolina.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Curriculum Vitae

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EDUCATION:

University of Massachusetts / Boston
Ph.D., Public Policy, 1997
Dissertation: Fiscal Policy Perversity in State and Local Government Spending

University of Chicago
M.A., Social Science, 1980
Concentration: Economic Policy
Thesis: The Economic Effects of Price Fixing Cases

Boston College
B.A., magna cum laude, 1977
Major: Economics

EXPERIENCE:

Vice President and Chief Power Strategist

2004 to present IHS, Cambridge MA.

Maintain senior client relationships, present IHS/CERA research, conduct multi-client studies, deliver consulting engagements and advance energy research.

Senior Director

6/94 to 2004 Cambridge Energy Research Associates, Cambridge MA.

Established CERA electric power business and managed the CERA Americas Group. Provided strategic planning support and delivered the research agenda to clients.

Principal

12/80 to 6/94 DRI/McGraw-Hill, Lexington, MA.

Served as the senior economist for electricity market analysis. Developed the DRI Electricity Market Model, prepared periodic forecasts, wrote review articles, conducted economic studies, performed policy analyses, and contributed as a member of the DRI Macroeconomic forecasting council.

Instructor

1989–1994 Northeastern University Graduate Business School, Boston, MA.

Taught both the macroeconomic and microeconomic courses in managerial economics.

Research Associate

1977–1979 National Economic Research Associates, New York, NY

Prepared analyses and testimony for electric utility rate and antitrust cases.

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SELECTED PUBLICATIONS:

1. *Power Supply Cost Recovery: Bridging the Missing Money Gap*, IHS CERA Private Report, 2013
2. *Too Much, Too Fast: The Pace of Greening the Ontario Power System*, IHS CERA Private Report, 2012
3. *The Volker Rule: Impact Assessment on the US Energy Industry and Economy*, (Chapter 3) IHS CERA Multi-client Study, 2012
4. *Recalibrating Power Supply Cost Assessments: Accounting for Integration*, IHS CERA Private Report, 2012
5. *The Smart Grid: Separating Perception from Reality*, "Issues in Science and Technology, National Academy of Sciences, Spring 2011
6. *The "Smart Grid Narrative" and the "Smarter Grid": Revolution versus Evolution—Which Way Forward*, IHS CERA Multi-client Study, 2010 (with co-authors)
7. *Putting Energy Back to Work, Energy for Economic Growth*: Energy Vision 2012, World Economic Forum, 2012
8. *The US Power Demand Tug-of-War*, IHS CERA Private Report, 2011
9. *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda*, (Chapter 6), IHS CERA Multi-client Study, 2010
10. *Energy Efficiency—An Investment Perspective, Towards a More Energy Efficient World: Energy Vision 2010*, World Economic Forum, 2010
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14. *Renewable Portfolio Standards: Getting Ahead of Themselves*, IHS CERA Private Report, 2008
15. *Gauging the Right Price*, IHS CERA Private Report, 2008
16. *Power Plant Valuation Cycles: Living with the Boom-and-bust Cycle*, IHS CERA Decision Brief, 2007
17. *California Power Crisis Aftershock: The Potential Modification of Western Power Contracts*, IHS CERA Private Report, 2007
18. *Meeting the Power Conservation Investment Challenge*, IHS CERA Private Report, 2007
19. *Does Earnings Quality Matter in the Power Business*, IHS CERA Decision Brief, 2006
20. *Electric Power Watch*, Cambridge Energy Research Associates, 1994 to 2006.
21. *Auctions for Retail Electric Service: Bringing Risk to Light*, CERA Decision Brief, 2004
22. "California in the Dark," with Daniel Yergin, *The Washington Post*, March 16, 2001.
23. *Beyond California's Power Crisis: Impact, Solutions, and Lessons,* with Michael Zenker, Daniel Yergin, Thomas R. Robinson, and Peter F. Moritzburke, Cambridge Energy Research Associates Special Report, March 2001.
24. *Electric Power Trends 2001,* with John P. Villali, David Clement, Paul Parshley, Joseph Sannicandro, Steven Taub, and Jone-Lin Wang, Arthur Andersen and Cambridge Energy Research Associates, September 2000.
25. *High Tension: The Future of Power Transmission in North America,* with Paul Parshley and Mark Smith, Cambridge Energy Research Associates, Autumn 2000.

26. *Knocking More NOx Out of Power Generation: How Much? Who Pays?,* CERA Private Report, 1999
27. *Midwest Wholesale Power Markets: Ready for a Repeat?,* CERA Decision Brief, 1999
28. *Ontario's Nuclear Crisis—The Impact Reaches Far Beyond Its Borders,* CERA Private Report, 1998
29. *Reshaping the North American Electric Power Industry: Scenarios 2010,* with Gary Simon and Bruce Humphrey, Cambridge Energy Research Associates, 1996.
30. *Spot Market Pricing of Electricity: Towards a New Market,* with Joseph Sannicandro, Cambridge Energy Research Associates, August 1996.
31. "Revaluing Generating Assets in the Changing Competitive Market," *Proceedings of the 26th Annual Wichita Workshop on Appraisal for Ad Valorem Taxation of Communications,* Energy and Transportation Properties, August, 1996.
32. *Cost vs. Worth: Revaluing Generating Assets in a Competitive Market,* Cambridge Energy Research Associates, July 1995.
33. "Reality Check: US Electricity Demand at the End of a Rebound," CERA Briefing Note, 1995.
34. "Over the Horizon: New Views of the Electric Power Industry," with Bruce Humphrey and Gary Simon, *Electrical World,* November 1994.
35. 1983 to 1994, regularly authored the DRI/McGraw-Hill electric industry outlook article. Numerous policy and analyses articles appearing in several of the DRI/McGraw-Hill energy publications and *Electrical World* magazine.
36. "Potential for Repowering in the Electric Generation Sector: Impacts on Natural Gas Demand," with Paul Holtberg, *Proceedings of the 15th Annual North American Conference of the International Association for Energy Economics,* October, 1993.
37. "Independent Power," *Institutional Investor*, October, 1991.
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40. "The Impact of Global Warming on the Electricity Utility Industry," with Seth Hollander and Joseph Sannicandro of DRI and Dr.Wei-Chyung Wang and David Chang of Atmospheric and Environmental Research Inc., DRI/McGraw-Hill *Electricity Review*, Summer 1989.
41. "Electricity Market Deregulation," *Competition, Profitability and Policy in the Energy Industries,* Guy Caruso (ed.), IAEE, 1988.
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43. *U.S. National and Regional Impacts of Nuclear Plant Life Extension,* Issued by Sandia National Laboratories, Albuquerque, New Mexico for U.S. Department of Energy, January 1988. NTIS SAND87-7136.
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TESTIMONY BEFORE U.S. CONGRESS:

January 31, 2001 – Washington, DC
United States Senate Committee on Energy and Natural Resources
Committee Chairman: Frank H. Murkowski, Senator from Alaska
"California's Electricity Crisis and Implications for the West"

March 22, 2001 – Washington, DC
United States House of Representatives Committee on Energy and Commerce
Subcommittee on Energy and Air Quality
Committee Chairman: Joe Barton, Representative from Texas
"Electricity Makets: California"

April 10, 2001 – Sacramento, CA
United States House of Representatives Committee on Government Reform
Committee Chairman: Dan Burton, Representative from Indiana
Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs
Committee Chairman: Doug Ose, Representative from California
"Assessing the California Crisis: How Did We Get to this Point, and Where Do We Go From Here?"